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ACRONYM DEFINITIONS

ADEC	Alaska Department of Environmental Conservation
API	American Petroleum Institute
BAT	Best Available Technology
CFR	Code of Federal Regulations
CPM	Computational Pipeline Monitoring
DOT-OPS	U.S. Department of Transportation Office of Pipeline Safety
EPA	U.S. Environmental Protection Agency
LDS	Leak Detection System
MTU	Master Terminal Unit
PLC	Programmable Logic Controller
RTTM	Real Time Transient Modeling
RTU	Remote Terminal unit
SCADA	Supervisory Control and Data Acquisition

PREAMBLE

Analysis of recent data from the U.S. Department of Transportation Office of Pipeline Safety (DOT-OPS) indicates that, despite stricter regulations and enforcement, the rate at which pipeline accidents occurs has not significantly changed over the last two decades (Hovey and Farmer, 1999). The statistics suggest that short pipelines will have at least one reportable accident during a 20-year lifetime and longer pipelines (800 or more miles of line pipe) can expect a reportable incident every year.

Research indicates that the best opportunities to mitigate pipeline accidents and subsequent leaks are through prevention measures such as aggressive controller training and strict enforcement of safety and maintenance programs (Hovey and Farmer, 1999; Borener and Patterson, 1995). The next most productive enhancement comes from implementing better pipeline monitoring and leak detection equipment and practices. Early detection of a leak and, if possible, identification of the location using the best available technology allows time for safe shutdown and rapid dispatch of assessment and cleanup crews. An effective and appropriately implemented leak detection program can easily pay for itself through reduced spill volume and an increase in public confidence.

Recognizing the importance of leak detection in the prevention of oil spills and the need for a more thorough understanding of the use and effectiveness of leak detection technologies used by the Alaska oil industry, the Alaska Department of Environmental Conservation (ADEC) developed best available technology (BAT) regulations for inclusion in their spill prevention assessment program. ADEC issued a contract to identify, analyze, and report on technologies and systems that can be used to detect leaks in crude oil transmission pipelines to meet the requirements of 18 AAC 75.055(a) and 18 AAC 75.425(e)(4)(A)(iv). Identifying strengths and weaknesses in leak detection technologies will help the Industry Preparedness and Pipeline Program of ADEC make further improvements in preventing oil spills via strategic implementation of the BAT regulations.

Ideally leak detection vendors could state exactly how their systems would perform on a given pipeline configuration prior to installation. In practice, predicting performance is often difficult due to variability in product characteristics (density, viscosity), pipeline parameters (diameter, length, elevation profile), and process instrumentation variables (flow, temperature, pressure). The focus of this manual is to identify the various types of leak detection systems (LDSs), define a set of criteria for evaluating the performance of these systems that can be adapted to a wide range of operating pipeline systems, and provide a general evaluation of each leak detection technology to facilitate both choosing the appropriate system and evaluating the system according to BAT regulations. This manual should be regarded as a dynamic tool for BAT evaluations and should be updated periodically.

1 INTRODUCTION

1.1 OBJECTIVES

The overall purpose of this project is to identify strengths and weaknesses in industry crude oil pipeline leak detection operations and gain enough information for strategic implementation of the State of Alaska best available technology (BAT) regulations. This manual is to be used as a guidance document by the Alaska Department of Environmental Conservation (ADEC), oil industry representatives, and the public.

Project background information, regulatory framework, and research methodology are discussed in the main body of this document. Also presented are detailed discussions of the various types of leak detection systems available today. Individual evaluations for each leak detection technology are presented by vendor name under the tab "Leak Detection System Evaluations".

1.2 PROJECT BACKGROUND

In response to questions from industry and the regulatory community regarding the BAT regulations, ADEC issued a contract to identify, analyze, and report on technologies and systems that can be used to detect leaks on crude oil transmission pipelines. The technology set reviewed under this scope of work was intended to include any potential candidate technology selected by the oil industry interests in Alaska to meet the requirements of 18 AAC 75.055(a) and 18 AAC 75.425(e)(4)(A)(iv).

Due to recent changes in the regulations, BAT reviews are a required element of Oil Discharge Prevention and Contingency Plan documentation. The Plan must identify and include a written analysis of all available leak detection technologies using the applicable criteria in 18 AAC 75.445(k)(3); and include written justification that the proposed technology is the best available for the applicant's operation. The technical and performance information may be used by ADEC, industry representatives, and the public as a reference aid to determine an individual technology's suitability with respect to the general requirements of 18 AAC 75.055(a), and specific requirements of 18 AAC 75.445(k)(3). In addition, the information in this report may assist pipeline controllers in preparing the written analysis contained in BAT reviews for pipeline leak detection systems (LDSs).

1.3 REGULATORY FRAMEWORK

The U.S. Department of Transportation's Office of Pipeline Safety (DOT-OPS) regulates the transportation of hazardous liquids under the Code of Federal Regulations as legislated through the Pipeline Safety Act and its reauthorizations (49 CFR 195). These regulations were originally adapted from national standards, such as the ASME B31.4, but have evolved over time to address specific concerns of the public and Congress, typically in response to a highly visible pipeline release.

Beginning July 6, 1999, under 49 CFR Part 195, DOT-OPS will require all controllers of hazardous liquids pipelines engaged in pipeline leak detection known as computational pipeline monitoring (CPM) to use, by reference and with other information, American Petroleum Institute (API) document API 1130 *Computational Pipeline Monitoring*. Noteworthy sections of the rule include 195.2 which defines CPM; 195.3 which incorporates API 1130 into Part 195; Subpart C Design Requirements (195.134) which outlines the requirement for a CPM system; and Subpart F Operation and Maintenance (195.444) which outlines compliance with API 1130.

API 1130 defines CPM as an algorithmic, computer-based monitoring tool which allows the pipeline controller to respond to an anomaly that may indicate product release. Controllers who have no such computer-based leak-detection system are not required to install one, but those currently running such a system, or installing one in the future, must consult API 1130 in designing, evaluating, operating, maintaining, and testing their CPM systems.

BAT regulations applicable to Alaskan oil facilities and vessels became effective on April 4, 1997. All oil discharge prevention and contingency plans or plan renewals submitted to ADEC after this date must undergo a BAT review before they are approved. Elements of operations requiring the BAT review are specified in 18 AAC 75.425(e)(4). The pipeline leak detection requirement under 18 AAC 75.055(a) states that a crude oil transmission pipeline must be equipped with an LDS capable of promptly detecting a leak, including:

- If technically feasible, the continuous capability to detect a daily discharge equal to not more than one percent of daily throughput;
- Flow verification through an accounting method, at least once every 24 hours; and
- For a remote pipeline not otherwise directly accessible, weekly aerial surveillance, unless precluded by safety or weather conditions.

Under the leak detection requirement, applicants must identify all available and proven technology alternatives. Each alternative must then be evaluated in relation to the technology in place or proposed based on the criteria provided in 18 AAC 75.445(k)(3) and summarized below:

- Availability;
- Transferability;
- Effectiveness;
- Cost;
- Age and Condition;
- Compatibility;
- Feasibility; and
- Environmental Impacts.

Once this evaluation has been completed, the applicant must then provide written justification for each applicable technology determined to be the best available for the applicant's operation.

2 RESEARCH/DATA COLLECTION

The approach to researching available pipeline leak detection technologies included performing internet and literature searches for viable leak detection vendors and technologies, attending related workshops, and contacting and soliciting information from vendors and industry users. The reference materials obtained during the research phase of this project were cataloged and are available at ADEC Division of Spill Prevention and Response in Anchorage.

2.1 INTERNET SEARCH

An Internet search for leak detection vendors and oil companies using LDSs was performed. The search identified approximately 50 potential vendors and several oil companies, both domestic and foreign. Another 20 to 30 vendors were identified in the literature. Several of these vendors were immediately eliminated because they were no longer “in the business” or they dealt solely with fuel storage tank leak detection measures.

2.2 LITERATURE SEARCH

A great deal of leak detection literature was obtained from a variety of sources including API, the U.S. Environmental Protection Agency (EPA), the Oil and Gas Journal database, and Gulf > Publishing. A complete set of references is available for review at ADEC. An alphabetized list of references is presented in Section 5.

2.3 WORKSHOPS AND CONFERENCES

ARCO Alaska Inc. and British Petroleum-Amoco sponsored a one-day leak detection workshop on April 6, 1999. One vendor, EFA Technologies, Inc., and industry representatives from ARCO, BP-Amoco, and Alyeska Pipeline Service Company were present. The workshop included a presentation on leak detection regulatory requirements, an overview of pipeline LDSs, and analyses of operational and proposed LDSs on Alaska crude oil transmission pipelines.

ADEC’s contractor also attended the annual API Pipeline Conference in Dallas, Texas (April 20-21, 1999). A variety of leak detection information was obtained from vendors and oil industry representatives.

2.4 VENDORS

Sixty-seven leak detection vendors were contacted via email, fax, or phone and were sent a detailed questionnaire. Vendors were asked to complete the questionnaire and return it with product literature and a client reference list. Approximately 20 responses were received. Credible references identified by vendors were contacted to determine the veracity of vendor claims. A complete list of viable pipeline LDS vendors identified and evaluated is presented below.

- Acoustic Systems, Inc.
- Controlotron Corporation
- DETEX International
- EFA Technologies, inc.
- EnviroPipe Applications, Inc.
- FCI Environmental, Inc.
- LICEnergy, Inc.
- Løgstør Rør
- National Environmental Services Company (NESCO)
- PermAlert
- Physical Acoustics Corporation

- Raychem Corporation
- Siemens AG
- Simulutions Inc.
- Stoner Associates
- Tracer Research Corporation

2.5 INDUSTRY

Several companies in Alaska, the lower 48, and around the world were contacted, interviewed, and sent questionnaires to assess the effectiveness of pipeline LDSs presently being used in the field. Industry representatives were also interviewed at the annual API Pipeline Conference. A list of industry representatives that directly or indirectly participated in this project is presented below.

- Alyeska Pipeline Services Company
- Amoco Canada Petroleum Company. Ltd.
- ARCO Alaska, Inc.
- Bahrain Petroleum Company
- Boeing Petroleum Services
- British Petroleum-Amoco Alaska
- Buckeye Pipeline Company
- Cenex Pipeline
- Cook Inlet Pipeline Company
- CrossTimbers Operating Company
- Enbridge Pipeline
- Federated Pipelines Ltd.
- Marathon Oil Company
- Mid-Valley Pipeline
- Pennzoil Company
- Phillips Petroleum Company
- Shell Oil Products
- Sun Pipeline Company
- Texaco Company
- TransAlpine Company
- Trans Mountain Pipeline Company
- Unocal Corporation
- U.S. Defense Fuel Supply Command

3 PIPELINE LEAK DETECTION SYSTEMS

Methods used to detect product leaks along a pipeline can be divided into two categories, externally based (direct) or internally based (inferential). Externally based methods detect leaking product outside the pipeline and include traditional procedures such as right-of-way inspection by line patrols, as well as technologies like hydrocarbon sensing via fiber optic or dielectric cables. Internally based methods, also known as computational pipeline monitoring (CPM), use instruments to monitor internal pipeline parameters (i.e., pressure, flow, temperature, etc.), which are inputs for inferring a product release by manual or electronic computation (API, 1995a).

The method of leak detection selected for a pipeline is dependent on a variety of factors including pipeline characteristics, product characteristics, instrumentation and communications capabilities, and economics (Muhlbauer, 1996). Pipeline systems vary widely in their physical characteristics and operational functions, and no one external or internal method is universally applicable or possesses all the features and functionality required for perfect leak detection performance. However, the chosen system should include as many of the following desirable leak detection utilities as possible (API, 1995a):

- Possesses accurate product release alarming;
- Possesses high sensitivity to product release;
- Allows for timely detection of product release;
- Offers efficient field and control center support;
- Requires minimum software configuration and tuning;
- Requires minimum impact from communication outages;
- Accommodates complex operating conditions;
- Is available during transients;
- Is configurable to a complex pipeline network;
- Performs accurate imbalance calculations on flow meters;
- Is redundant;
- Possesses dynamic alarm thresholds;
- Possesses dynamic line pack constant;
- Accommodates product blending;
- Accounts for heat transfer;
- Provides the pipeline system's real time pressure profile;
- Accommodates slack-line and multiphase flow conditions;
- Accommodates all types of liquids;
- Identifies leak location;
- Identifies leak rate;
- Accommodates product measurement and inventory compensation for various corrections (i.e., temperature, pressure, and density); and

- Accounts for effects of drag reducing agent.

The following sections present a detailed discussion of the major components of a typical computer-based pipeline LDS, as well as descriptions of several externally and internally based leak detection technologies. For each technology, a list of evaluated vendor-specific systems is presented.

3.1 MAJOR COMPONENTS OF A COMPUTER-BASED LDS

The utilization of computer systems in pipeline monitoring allows the greatest amount of data to be collected, analyzed, and acted upon in the shortest amount of time. For these reasons, most pipeline systems today employ some form of computer-based monitoring using commercially available or custom-designed software packages to run the system (Furness and van Reet, 1998). Leak detection is just one of many functions that can be performed with computer-based systems, which generally consist of two major elements: instrumentation and a supervisory computer with associated software and communications links.

3.1.1 Instrumentation

Instrumentation includes the flow meters, pressure transducers, sensors, and cables situated along the pipeline (externally or internally) which measure parameters such as line pressure, temperature, flow, product characteristics, and the presence of hydrocarbons. Because the effectiveness of any pipeline LDS is limited primarily by the sensitivity and accuracy of the installed instrumentation, it is critical to select the best performing setup for a given operating scenario. Instrument specifications should be prudently compared to a pipeline's operating design to make the best use of the manufacturer's declared accuracy and linearity (API, 1995a). Additionally, all practical means should be taken to reduce sources of instrument noise[1], which can inhibit the performance of an LDS. Mechanical resonance and electrical interference are primary sources of instrument noise. Mechanical resonance must be considered during the design of process piping and placement of the instrument package. Proper instrument grounding and the use of shielded signal cables will serve to reduce electrical noise. If these measures of noise reduction are not successful, signal conditioning (bandwidth adjustment, digital filters, or data smoothing programs) may be required.

Another means of reducing the impact of mechanical noise on pipeline systems is the use of inline surge or divert tanks. Popular in the lower 48 states and used on at least one North Slope line, surge tanks lessen the impact of pressure wings and system noise on meters that could potentially result in measurement errors, damage, or undue wear. Surge tanks may result in an increase in leak detection sensitivity by allowing the operator to lower alarm thresholds.

McAllister (1998) provides some general guidelines to follow when selecting field instrumentation:

- Choose instrumentation based on performance and not economic grounds. It is better to install fewer high quality pieces of equipment than numerous poor ones.
- Equipment compatibility is important. Use transducers, interface modules, and other hardware that use standard communications protocol.

[1] Noise is that part of a signal that does not represent the quantity being measured (API, 1995a). Fluctuations around a fixed or moving mean are considered noise.

- Where possible, install instruments that are self-checking or self-diagnosing, or install dual systems.
- Seek independent references, user experience, or validation of the instruments chosen. Most equipment performs differently in real applications than under the published ideal conditions.

Pipeline flow meters and pressure transducers are described below. Other sensors, cables, and instruments specific to LDSs are described in Sections 3.2 or 3.3, as appropriate. To supplement this discussion, API Publication 1149, *Pipeline Variable Uncertainties and Their Effects on Leak Detectability*, also documents the importance of field instrumentation to leak detection performance.

3.1.1.1 Flow Meters

Flow measurement is the most important process variable in the operation and control of pipelines; therefore, flow meters are one of the most important instruments installed on a system (McAllister, 1998). Several different types of flow meters are used on pipelines including orifice plates (differential pressure), turbine, positive displacement, mass flow (Coriolis type), and ultrasonic time-of-flight (clamp-on)[2]. This section describes the various types of flow meters, their accuracies, advantages, and disadvantages.

The flow meters most often installed on pipelines are sharp-edged orifice plates, a differential pressure type of meter. Although the use of these types of meters is very common in processes such as the metering of natural gas, their use as accurate instrumentation for pipeline leak detection is questionable. The biggest problem is the measurement uncertainty associated with these instruments. Vendors claim orifice plates are accurate to within 0.5% of flow; however, when all the other variables that can affect uncertainty measurement are considered—fluid composition changes, temperature and pressure variations, conversion and computational errors, etc.—it is unreasonable to assume that accuracies better than 3 to 5% can be achieved (McAllister, 1998).

Turbine meters are flow-measuring devices with rotors that sense the velocity of flowing liquid in a closed conduit. The flowing liquid forces the rotor to move with a tangential velocity proportional to the volumetric flow rate (API, 1995c). Turbine meters are used extensively on pipelines, especially those carrying petroleum hydrocarbons (McAllister, 1998). Among the instruments in this family of flow meters are the custody transfer meters used to bring oil to market. Turbine flow meters tend to be more accurate than other types (i.e., custody transfer meters are reportedly accurate to within 0.05% of throughput), but still suffer from limitations such as calibration shift. Their volumetric accuracy depends on the measured dimensions of the pipeline section, the amount of drag in the turbine's rotor, and the degree of system proving. Fortunately, recent developments have resulted in self-diagnosing twin rotor meter designs, which can detect shifts in calibration caused by bearing wear and blade damage (McAllister, 1998). The microprocessors in these twin rotor meters can also check the integrity of the data generated by the meters and provide alarm output for verified problems. Other variables that may affect turbine meter performance are variations in flow rate, viscosity, temperature, density, and pressure (API, 1995c).

[2] Regardless of how volumetric flow is measured or computed, API standards require that all meters be "proven" or regularly calibrated against a known and accepted standard.

Positive displacement meters measure flow by moving the liquid through a pipe section of known volume. The claimed accuracy of these meters is 0.1 to 0.2% of flow. The accuracy of these meters depends on the accuracy to which the dimensions of the pipe section are known, the extent to which it effectively contains the product, and the temperature and pressure conditions under which the measurements are made (Diane Hovey, EFA Technologies, written commun., 1999).

Another flow meter that is slowly gaining acceptance and being incorporated into the pipeline industry is the Coriolis direct mass meter (McAllister, 1998). The accuracy of these instruments is approximately +/-0.5% of reading or better. The advantage of direct mass measurement over the more common volumetric assessment is that the integration of the instrument signal provides the pipeline fluid inventory directly. Additional measurements of temperature, pressure, and equation of state to determine fluid density are not necessary. The principal disadvantage is the current size range of the meters. Most major pipelines are in the 500 to 2,000 millimeter (mm) bore range, but the largest available direct mass meter is only 150 mm bore. This means that several Coriolis meters would have to be installed in parallel to be effective. Additionally, API does not envision that these meters will be used for custody transfer measurements in the near future.

The ultrasonic transit-time flow meters are installed on the outside of the pipeline. These clamp-on flow meters are reportedly accurate to within 0.001 ft/sec at any flow rate, including zero. However, measurement engineers hold the installed accuracy of these meters to be no better than 2% of flow (McAllister, 1998). Ultrasonic meters have the advantages of negligible headloss and the ability to install additional instrumentation without line shutdown.

3.1.1.2 Pressure Transducers

Pressure-measuring devices may be divided into three groups: those based on measurement of the height of a liquid column; those based on measurement of the distortion of an elastic pressure chamber; and electronic sensing devices. Conventional pressure transducers found on pipelines generally are of the electronic sensing type with various means of discerning pressure (piston, diaphragm, strain gauge, piezoelectric sensors, variable capacitance, and variable element). Pipeline pressure is measured by the displacement of these devices in response to fluid pressure and is converted electronically to an appropriate current, voltage, or digital output signal. The sensors typically are ceramic, silicon, or stainless steel. Ceramic is corrosion and abrasion resistant, has superb electrical isolation, and a high natural frequency. Silicon, an elastic drift-free material, offers low cost and is the most common material used. The accuracy of these transducers is typically +/-0.1% of span.

Recent developments in microprocessing have resulted in the creation of a new generation of "smart" pressure transducers. These intelligent sensors rely on the properties of silicon and microelectronics for optimum performance (McAllister, 1989). The advantages of these transducers are listed below.

- Signal processing is digital and algorithms can be written to cope with any signal/pressure curve, provided it is repeatable;
- Advanced communications capabilities, including remote access and online instrument rearranging;
- On-line temperature compensation;

- Built in diagnostics; and
- Claimed accuracies of better than +/-0.1% of span.

Another type of pressure transducer that has potential pipeline applications is the vibrating wire sensor. This transducer operates on the premise that as pressure changes, the tension on a tungsten wire enclosed in a silicon diaphragm is altered, and the result is a measurable change in the resonating frequency of the wire (McAllister, 1998). The change in frequency is sensed and amplified, and data are provided to the pipeline controller. Pressure and temperature compensation is accomplished within the instrument. While it has shown considerable reduction in size and manufacturing costs from other sensors, this technology is still in the experimental stage and has not been extensively applied in the field.

3.1.2 SCADA/Communications

The Supervisory Control and Data Acquisition (SCADA) system is a computer-based communications system that monitors, processes, transmits, and displays pipeline data for the controller (API, 1995a; Borener and Patterson, 1995). SCADA systems may be used directly for leak detection, they may provide support for an LDS, or an LDS may operate independently of SCADA. Generally, a pipeline LDS will use the data generated by a SCADA system to aid in assessing the potential for a product release.

SCADA systems collect real-time data from field instruments using Remote Terminal Units (RTUs), Programmable Logic Controllers (PLCs), and other electronic measurement devices, which are placed at intervals along the pipeline. Communication with these devices can occur in many ways, including microwave, cellular, satellite, leased line, etc., but the most common media are dedicated phone circuits and terrestrial- and satellite-based radio systems (API, 1995a). An emerging trend is to use multiple methods of communicating based on the concept that each method will have a cost or performance advantage for a given installation (Whaley and Wheeler, 1997).

Data from RTUs or PLCs are gathered into a Master Terminal Unit (MTU) which consists of one or more central computers built around a real-time, memory-resident database. The MTU displays the current operating conditions for the controller, who, in turn, can act on these data if necessary. Messaging between the field devices and the MTU is known as the communications protocol (API, 1995a). The protocol is considered “polled” when the MTU requests data from each device consecutively. When the last device is scanned, the MTU will automatically request information from the first one, creating a ceaseless polling cycle. The SCADA system polling rate, the time between successive communications between the RTU and MTU, has steadily improved over the years and has been reduced to less than 0.25 seconds in high priority areas on some pipelines (Ed Farmer, presentation, April 1999). SCADA communications may also be non-polled. For example, RTUs may report without being polled on a time-scheduled basis or when field conditions change. LDSs that rely on the SCADA system to receive operating data are directly affected by the polling rate. Longer polling cycles typically translate to degraded leak detection sensitivity.

Most modern SCADA systems include quality checking software to assess the validity of the data before any calculations are computed and displayed (McAllister, 1998). Research suggests that this type of continuous quality control greatly improves the sensitivity of the system. In addition, advanced SCADA systems can include predictive modeling to assess “what if” operating scenarios, handle automatic startup and shutdown routines, and evaluate operating strategies for cost-benefit optimization (McAllister, 1998).

For additional discussion of SCADA system design factors and their effects on the quality and timeliness of the data required by an LDS, see API Document 1130, *Computation Pipeline Monitoring* (1995a).

3.2 INTERNAL LEAK DETECTION SYTEMS

Results of the literature search have shown that the main category of inferential leak detection in pipelines is known as computational pipeline monitoring (CPM). CPM refers to algorithmic monitoring tools that are used to enhance the abilities of a pipeline controller to recognize anomalies which may be indicative of a product release (API, 1995a). CPM operates by providing an alarm and displaying other related data to the controller who, in turn, would investigate the reason for the alarm and initiate a response if the anomaly represents a product release. CPM does not include externally based LDSs which operate on the non-algorithmic principle of physical detection of a product leak (API, 1995a). Externally based leak detection methods are presented in Section 3.3.

CPM mainly relies on the data collected from the field instruments, which are continuously input into a computer program that mathematically or statistically analyzes the information. Analysis results are produced in the form of parameter estimates, which in turn are subjected to some probability law or decision criteria to determine if a leak is present (API, 1995b). The degree of complexity in analyzing field data ranges from the comparison of a single element (i.e., pressure) relative to a threshold limit to extensive analyses of multiple elements with dynamic thresholds. Without the computer program and associated algorithms, the data would be difficult if not impossible to interpret in a timely manner. Consequently, the heart of any CPM system is the computer program. The classes of CPM are differentiated by the types of instruments and programs (or algorithms) used. There are three basic types of CPM: volume (or mass) balance, pressure analysis (rarefaction wave monitoring), and real time transient modeling (RTTM). Note that some of the leak detection systems offered by vendors include more than one type of leak detection method (i.e., both volume balance and pressure analysis). Additionally, most of the volume balance and RTTM leak detection systems use some sort of pressure analysis to locate leaks.

3.2.1 Volume Balance

The volume balance method of leak detection, also known as line balance, compensated volume balance, or mass balance, is based on measuring the discrepancy between the incoming (receipt) and outgoing (delivery) product volumes of a particular pipeline segment (API, 1995a). During a unit time interval, the volume of product that enters a pipe may not be equal to the measured volume exiting the pipe. The difference is accounted for by uncertainties in line pack and flow measurement. This relationship is stated below:

$$\left|Q_{in} - Q_{out}\right| \leq dQ_m + \frac{dV_s}{\Delta t}$$

Where,
Q_{in} = Measured Inflow
Q_{out} = Measured Outflow

dQ_m = Bound of uncertainty in flow measurement
dV_s = Bound of uncertainty in line pack change over a time interval Δt

If a leak exists it can only be detected if the following relationship is fulfilled:

$$Q_l = Q_{in} - Q_{out} > dQ_m + \frac{dV_s}{\Delta t}$$

Where,
Q_l = Flow rate of the leak

The principal differences among the various volume balance methods are outlined below.

- Basic line balance does not compensate for changes in line pack due to pressure, temperature, or product composition.
- Volume balance is an enhanced, automated technique, which does account for line pack correction by assessing changes in volume due to temperature and/or pressure variations. A representative bulk modulus is used for line pack calculations.
- Compensated volume balance is an enhanced volume balance technique which accounts for volume change using a dynamic bulk modulus to assess line pack correction.
- Mass balance accounts directly for product density (i.e., with online densitometers).

Ultrasonic systems detect leaks via transient-compensated volume or mass balance; therefore, they are included under this heading. These systems typically operate through accurate tracking of flow rate, computation of pressure, temperature, and product characteristics, and determination of sonic profiles using external clamp-on instruments configured with data processing equipment.

Compared to other leak detection methods, volume balance is particularly useful in identifying small leaks. However, leaks are generally detected more slowly and flow metering at each end of the line or pipeline segment will not identify the location of the leak. Most of the software-based volume-balance systems incorporate additional algorithms for leak location based on pressure analysis.

Volume balance LDSs that were evaluated for this project include EFA Technologies, Inc.'s MassPack™ (part of their LEAKNET™ system) and EnviroPipe Applications, Inc.'s LEAKTRACK 2000. Ultrasonic systems include Controlotron Corporation's System 990LD™ and DETEX International's Series 2000. The BAT evaluations for these technologies are presented under the tab "Leak Detection System Evaluations".

3.2.2 Pressure Analysis (Rarefaction Wave Monitoring)

The rarefaction wave (also called an acoustic, negative pressure, or expansion wave) method of leak detection is based on the analysis of pipeline pressure variations. When product breaches the pipeline wall there is a sudden drop in pressure at the location of the leak followed by rapid line repressurization a few milliseconds later. The resulting low-pressure expansion wave travels at the speed of sound through the liquid away from the leak in both directions. Instruments placed at intervals along the pipeline respond as the wave passes. If a leak occurs in the middle of a line segment with uniform construction, the rarefaction wave should be seen at opposite ends of the line simultaneously. If the leak is closer to one end, it should be seen first at the close end and later at the far end. The time evidence recorded at each end of the monitored line or segment is used to calculate the location of the leak. Most volume balance and RTTM leak detection systems use pressure analysis to locate leaks. Models also use pressure measurements as boundary conditions.

Since the rarefaction wave travels at significant speeds, on the order of one mile per second, this method of leak detection is particularly useful in identifying large leaks rapidly. Smaller leaks typically take longer to detect and very small, pinhole leaks may go undetected. The success of a rarefaction wave LDS largely depends on the frequency and sensitivity of instrument measurements. Because of the sensitivity of this type of technology to operational changes that result in large transient pressure waves, leak detection performance generally falls off under highly transient, slack-line, and multi-phase flow conditions.

The principal difference among the various rarefaction wave technologies is how the wave is identified and monitored. Some sensors or transducers monitor for the leading edge of the wave while others evaluate the shape of the wave.

Pressure analysis (rarefaction wave monitoring) LDSs that were evaluated for this project include EFA Technologies Inc.'s Pressure Point Analysis (PPA)™ (part of the LEAKNET™ system), Acoustic Systems Inc.'s WaveAlert®, and Tracer Research Corporation's LeakLoc®. The BAT evaluations for these technologies are presented under the tab "Leak Detection System Evaluations".

3.2.3 Real Time Transient Modeling

The most sensitive, but also the most complex and costly leak detection method in use is real time transient modeling (RTTM). RTTM involves the computer simulation of pipeline conditions using advanced fluid mechanics and hydraulic modeling (Borener and Patterson, 1995). Conservation of momentum calculations, conservation of energy calculations, and numerous flow equations are typically used by the RTTM system. RTTM software can predict the size and location of leaks by comparing the measured data for a segment of pipeline with the predicted modeled conditions. This analysis is done in a three-step process. First, the pressure-flow profile of the pipeline is calculated based on measurements at the pipeline or segment inlet. Next, the pressure-flow profile is calculated based on measurements at the outlet. Third, the two profiles are overlapped and the location of the leak is identified as the point where these two profiles intersect. If the measured characteristics deviate from the computer prediction, the RTTM system sends an alarm to the pipeline controller. The more instruments that are accurately transmitting data into the model, the higher the accuracy of and confidence in the model. Note that models rely on properly operating and calibrated instruments for optimum performance. Calibration errors can result in false alarms or missed leaks, and the loss of a critical instrument could require system shutdown.

The advantage RTTM provides over other methods is its ability to model all of the dynamic fluid characteristics (flow, pressure, temperature) and take into account the extensive configuration of physical pipeline characteristics (length, diameter, thickness, etc.), as well as product characteristics (density, viscosity, etc.) (API, 1995a). Additionally, the model can be tuned to distinguish between instrument errors, normal transients, and leaks. The distinct disadvantages of this LDS are the costs associated with implementing RTTM and the complexity of the system, which requires numerous instruments and extensive controller training and system maintenance.

RTTM LDSs that were evaluated for this project include LICEnergy Inc.'s Pipeline Leak Detection System (PLDS), Simulutions Inc.'s LEAKWARN, and Stoner Associate's SPS/Leakfinder. The BAT evaluations for these technologies are presented under the tab "Leak Detection System Evaluations".

3.3 EXTERNAL LEAK DETECTION SYSTEMS

3.3.1 Acoustic Emissions

Leak detection in pipelines using acoustic emissions technology is based on the principle that escaping liquid creates an acoustic signal as it passes through a perforation in the pipe. Acoustic sensors affixed to the outside of the pipe monitor internal pipeline noise levels and locations. These data are used to create a baseline "acoustic map" of the line. When a leak occurs, the resulting low frequency acoustic signal is detected and analyzed by system processors. Deviations from the baseline acoustic profile would signal an alarm. The received signal is stronger near the leak site thus enabling leak location.

Acoustic sensing can be applied externally to buried pipelines by using steel rods driven into the ground to conduct the sound to a sensor mounted on the rod. The rods are inserted at intervals along the pipeline.

Physical Acoustic Corporation's Acoustic Emissions LDS was evaluated for this project. The BAT evaluation for this technology is presented under the tab "Leak Detection System Evaluations".

3.3.2 Fiber Optic Sensing

With this technology, fiber optic sensing probes are driven into the soil beneath or adjacent to the pipeline. In the presence of hydrocarbons, the patented covering of the sensor changes its refractive index. This change is registered optically by the sensor and converted to a parts-per-million reading of hydrocarbons.

FCI Environmental, Inc.'s PetroSense® was the only LDS based on fiber optics evaluated for this project. The BAT evaluation for this technology presented under the tab "Leak Detection System Evaluations".

3.3.3 Liquid Sensing

Liquid sensing cables are buried beneath or adjacent to a pipeline and are specifically designed to reflect changes in transmitted energy pulses as a result of impedance differentials induced by contact with hydrocarbon liquids. Safe energy pulses are continuously sent by a microprocessor through the cable. The pulses are reflected and returned to the microprocessor. Based on the specific installation of the cable, a baseline reflection map is stored in the memory of the microprocessor. When a leak occurs, the cable is saturated with fluid. The fluid alters the impedance of the sensing cable, which in turn alters the reflection pattern returning to the microprocessor. The change in signal pattern causes the microprocessor to register a leak alarm at the location of the altered impedance. Controller interface software is available to provide real-time information on leak detection and record keeping. Specific cable types are chosen for each application based on the specific fluid being monitored.

Liquid sensing leak detection is typically marketed as a self-contained leak detection and location system, including all hardware and software. Advantages include relatively high accuracy in determining leak location, no modifications to existing pipeline, and easy software configuration and maintenance. Disadvantages include very high installation costs and extensive power and signal wiring requirements.

Liquid-sensing cable LDSs that were evaluated for this project include PermAlert's PAL-AT®, Raychem Corporation's TraceTek, and Løgstør Rør's LR-Detector. The BAT evaluations for these technologies are presented under the tab "Leak Detection System Evaluations".

3.3.4 Vapor Sensing

Hydrocarbon gas sensing systems are more frequently used in storage tank systems but can also be applicable to pipelines. Leak detection using vapor-monitoring techniques is a fairly straightforward concept. When a liquid seeps into the soil, vapors migrate from into the surrounding soil pore spaces. Probes are arranged in the soil so that a vacuum may be applied to them. The soil vapors are collected for laboratory or field analysis. Tracers or chemical markers may be added to the product being monitored so that it may be identified from naturally occurring background vapors. When the tracers or markers are encountered during analysis of the vapors, it can be surmised that a leak has occurred.

The vapor sensing tube leak detection method involves the installation of a secondary conduit along the entire length of the pipeline. The conduit may be a small-diameter perforated tube attached to the pipeline or it may completely encompass the pipeline, allowing the annular headspace to be tested. Air gas samples are drawn into the tube and analyzed by hydrocarbon vapor sensors to determine the presence of a leak. Because of the logistical problems associated with any system installed along the entire length of a pipeline, vapor-sensing tubes are usually only employed on short lines.

Vapor-sensing LDSs that were evaluated for this project include National Environmental Services Company's Soil Sentry 12XP, Tracer Research Corporation's Tracer Tight®, and Siemens AG LEOS® system. The BAT evaluations for these technologies are presented under the tab "Leak Detection System Evaluations".

3.4 PERFORMANCE ISSUES

The LDSs discussed in this report are affected by operational factors that may contribute to a deterioration of performance. This section discusses these factors as performance issues limiting the quality of data acquired by the LDS. A more detailed discussion of the limitations of CPM systems may be found in API Publication 1130, *Computational Pipeline Monitoring*.

3.4.1 Multiphase and Slack-Line Effects

Multiphase flow, the simultaneous flow of oil and gas or of oil, gas, and water through one pipe, can occur as a number of different flow patterns (McAllister, 1998):

1. Bubble flow — bubbles of gas flow along the upper part of the pipe at about the same velocity as the product;
2. Plug Flow — the bubbles of gas coalesce into large bubbles which occupy the large part of the cross-sectional area of the pipe;

3. Laminar Flow — the gas-liquid interface is relatively smooth with gas flowing in the upper portion of the pipe;
4. Slug Flow — the tops of some waves on the surface of the liquid reaches the top of the pipe. These slugs move with high velocity;
5. Annular Flow — the liquid flows along the walls of the pipe and the gas moves through the center with high velocity; and
6. Spray Flow — the liquid is dispersed within the gas.

Multiphase flow can occur in a petroleum pipeline for a number of reasons. In the case of crude oil gathering lines, water and gas can be produced with the oil in production wells of mature fields where water flood enhanced oil recovery is used to maintain field pressures, and/or the gas/oil ratio has become elevated following the removal of oil from the reservoir. Multiphase flow may be communicated to a delivery line fed by a production facility in the event its water or gas removal system malfunctions, or cannot keep up with surges of gas and water from gathering lines.

Because water, oil, and natural gas have significantly different physical characteristics, multiphase flow can cause line pressures to change as they pass a point in the line; thus, confounding attempts to gauge internal line pressures on a real-time basis. The erratic pressure swings caused by multiphase flow adversely affect the signal from pressure transducers and may lead to poor-quality input data and/or multiple false alarms.

Slack-line conditions occur where flow is not sufficient to keep the entire volume of the pipe filled with liquid. Under this condition, the pipeline will have “pockets” of volume not occupied by flowing liquid. These regions will be related to line topography and flow rates and, in effect, represent a transient storage term in modeling pipeline flow characteristics. Real time transient modeling is capable of dealing with this transient storage effect, albeit at degraded sensitivities, whereas volume balance methods may misinterpret loss to and gain from the slackline as a leak from or false input to the pipeline. Pressure analysis may also provide erratic results based on slackline volume changes and associated changes in the pressure-volume relationship within the slack-line areas.

3.4.2 Pre-Existing Leaks

Leaks existing during startup of a pressure analysis system will not be detected, rather, the pressure data used to calibrate and run the system will include the perturbation from the leak as the normal baseline condition. Similarly, small leaks that become larger may not be detected until their effect exceeds the rate-of-change boundary condition criteria set for the instruments. However, these situations are rare. Line and volume balance methods will detect such conditions provided the leak rate is greater than the precision limits of the metering devices used.

3.4.3 Variations in Temperature, Pressure, & Flow Conditions

Most RTTM, compensated volume balance, and pressure analysis systems are capable of correcting for pressure/temperature/volume (i.e., line pack) relationships within the pipeline. Line balance or other systems that do not account for these relationships may send false alarm signals because of apparent pressure or volume losses related to temperature changes.

3.4.4 Connected Production Areas

LDSs placed in a pipeline between two or more production areas may respond to flow rate and pressure fluctuations coming from upstream or downstream directions. Thus, operational transients in one production area or pipeline segment may be sensed as a leak by an LDS component assigned to another. Pressure analysis leak detection with leak location software should be capable of isolating the source area of suspect pressure anomalies within a section of pipeline. Sources of pressure change coming from outside the pipe segment being monitored by a given system will be flagged as foreign by the leak detection software. One way to minimize the effects of pressure anomalies on leak detection is to install in-line surge tanks, which reduce pipeline noise and enhance leak detection sensitivity (see Section 3.1.1).

3.4.5 False Alarms

As discussed, many factors contribute to an elevated signal-to-noise ratio with an internal LDS. Some factors are known (i.e., engineered production rate changes, well shut-ins, and diversion to and from tank storage), others are less predictable (slugging, effects from pipeline feed changes in connected production areas). Over time, repetitious false alarms may degrade the quality of response to future alarms irrespective of their cause. If possible, a threshold level of alarms per week or month may be prescribed based on systematic causes. This fine tuning may be achieved through the adjustment of SCADA analog deadband threshold settings or through the use of data filtering programs that eliminate, or at least flag, line perturbations caused by normal system fluctuations. Dangers exist in relying solely on changed settings to reduce the frequency of leak detection alarms. First, the precision required to detect a leak of a desired size may be lost if thresholds or filters attenuate or block the signal significantly. Second, the quality of the response to future alarms may become degraded if controllers become accustomed to long periods of time without reacting to them.

Use of rules-based logic or expert systems within an LDS will be a major enhancement in terms of reducing or eliminating the number of false alarms in the near future (Whaley and Wheeler, 1997). Most LDSs currently include simple rules for alarming when high or low limits are exceeded or when measured values change too rapidly. The problem with these simple limits is that they lead to a proliferation of frequently meaningless alarms and are unable to evaluate situations involving multiple points or sites. Rules-based logic has the potential of reducing the amount of data controllers must review while increasing the amount of meaningful information. Rules do this by automating the analysis performed by a controller to check out the meaning of limit alarms and by allowing more complex checks of multiple sites or values. Drawbacks to the use of these systems include the high cost of purchasing a third-party artificial intelligence package and the high degree of technical expertise required to set up and maintain it.

The number of false leak alarms appropriate for a given system is site and application specific. The frequency of false alarms and the appropriate response to them should be part of the operational program in a facility using any leak detection technology.

3.4.6 Instrumentation

Instrumentation used to detect changes in pressure, temperature, and flow, must be calibrated and checked routinely. API recommends that each pipeline company implement a test and calibration plan as part of a CPM operating and maintenance procedure. The calibration and testing of instrumentation in the LDS should be based on manufacturer recommendations and on historical LDS performance.

Additionally, the devices selected for incorporation into an LDS must afford sensitivity necessary to attain leak detection goals. For example, turbine meters may be selected over orifice meters for greater than one percent accuracy in flow modeling.

The sensitivity of a volume balance LDS is ultimately determined by the combined or aggregate accuracy of the flow meters themselves. Aggregate accuracy typically is evaluated in terms of the standard deviations of the individual meters involved in closing the mass balance, or the "root-sum-squared" method (D. Hovey, written commun., 1999). The basic formula is presented below.

Aggregate Meter Accuracy = Square Root ($a_1^2 + a_2^2 + a_3^2 + ...+ a_n^2$)

Where a_n is the accuracy of the nth meter.

For example, a system with two meters, each 2 percent accurate, would have an aggregate accuracy of 2.8 percent. If one of these meters is replaced by a meter that is 0.1 percent accurate, the aggregate accuracy would become 2.0 percent. Note that the accuracy of the least accurate meter controls this equation. Ideally, a system should be designed with the fewest number of high-quality sensing devices as practical.

3.4.7 Controller Training

Because of the complexity of LDS technology, the pipeline controller should be trained to recognize the significance of alarms and their potential causes. The significance of the measurement data and credibility of alarms generated by any LDS may be lost if the ability to perform this type of analysis is compromised. API divides alarms into three categories: data failure, transient pipeline operating condition, and possible product release. The pipeline controller must have adequate training to discriminate between the various causes of alarms and respond appropriately. Controller training should include response to a minimum number of false alarms and the use of tests simulating releases.

3.4.8 Redundant Systems

It should be emphasized that in some situations more than one LDS might be appropriate for attaining BAT. Redundant systems may offer faster detection speeds and lower leak volume thresholds than a single system. For example, a combination of mass balance (which can detect small volume leaks) and rarefaction wave analysis (which can detect large leaks very rapidly) would offer a combination of sensitivity, speed, and a leak location ability that might be considered BAT for a particular application.

4 LEAK DETECTION TECHNOLOGY EVALUATION

As noted in Section 1.3, the ADEC BAT evaluation is focused on the performance and suitability criteria listed in 18 AAC 75.445(k)(3). These criteria were combined with related performance and limitation considerations to construct a leak detection technology evaluation strategy. Note that ADEC's Age and Condition[3] criterion will not be used in the evaluation because it is a pipeline-specific parameter. Additionally, due to the variability in pipeline sizes and operating conditions, the leak detection Cost criterion is evaluated only qualitatively for each technology.

The evaluation criteria used in this assessment constitute just one set of general information that a pipeline company can use to determine the best available leak detection technology for their particular pipeline. They must also, on a pipeline-specific basis, be capable of performing the following functions:

- Identify any additional contractual or legal requirements relating to leak detection
- Characterize the pipeline in terms of its possible leak mechanisms and the likelihood that one of them will result in a leak. Factors include, but are not limited to, length and volume of the pipeline; pressure, temperature, and flow rate envelope; terrain; product characteristics; and pipeline operating and maintenance procedures;
- Determine the leak detection potential of the pipeline. A generic spreadsheet prepared by Enbridge Pipelines Inc. and based on principles outlined in API Publication 1149 (*Pipeline Variable Uncertainties and Their Effects on Leak Detectability*) is available on the floppy disc accompanying this manual or at ADEC; and
- Perform an assessment of definite and potential costs associated with incorrectly declaring leak alarms, missed alarms, late alarms, and any other deviation from ideal leak detection system performance (API, 1995b).

4.1.1 Applicability/Availability

The applicability criterion simply serves to ensure that any technology selected for use on a crude oil pipeline system was designed for that intended use. Availability refers to the commercial availability of an LDS and its components.

4.1.2 Effectiveness

Effectiveness deals primarily with the performance related aspects of an LDS and is evaluated in terms of sensitivity, accuracy, reliability, and robustness. Unfortunately, focus on attaining ideal performance in one area, say sensitivity, usually results in some degradation of the other criteria. To exemplify this, consider the following hypothetical leak detection systems (API, 1995b):

System I: This system employs a sensitive leak detection algorithm. The system is normally very reliable, but will frequently generate alarms during normal pipeline operations.

[3] This criterion refers to the age and condition of the leak detection technology in use by the applicant. If the existing leak detection system is being maintained in reliable operating condition, and is shown to have the capability to achieve the same expected results as a new technology, then ADEC may determine that there is no benefit in replacing the existing technology.

System II: This system employs an alternative algorithm which is somewhat less sensitive than that of System I, but generates only a fraction of the alarms.

System III: This system employs the same sensitive leak detection algorithm as System I, but inhibits leak detection during pipeline operations that can cause it to generate alarms.

System IV: This system normally employs the same sensitive leak detection algorithm as System I, but switches to the less sensitive algorithm of System II when it senses conditions that generate alarms.

In order to maintain a high level of sensitivity, the designers of System I have sacrificed a degree of reliability, whereas the designers of System II have decided to sacrifice some degree of sensitivity in order to achieve a high level of reliability. By disabling the leak detection capability under certain conditions, the designers of System III have sacrificed a degree of robustness in order to achieve higher levels of sensitivity and reliability. System IV represents and attempts to achieve a more robust system at the expense of sensitivity and reliability.

Most leak detection technologies attempt to attain a satisfactory tradeoff between sensitivity, accuracy, reliability, and robustness by understanding the specific operating conditions of a pipeline and the controller's expectations. The LDS ultimately selected by a pipeline company will depend upon the performance requirements specific to that company. No one LDS technology is suitable for all pipeline applications.

4.1.2.1 Sensitivity

Sensitivity is defined as the composite measure of the size of leak that a system is capable of detecting, and the time required for the system to issue an alarm in the event that a leak of that size should occur (API, 1995b). The relationship between leak size and the response time is dependent upon the nature of the LDS. Some systems manifest a strong correlation between leak size and response time, while with others, response time is largely independent of leak size. Note that there are no known systems that tend to detect small leaks more quickly than large leaks.

Sensitivity is evaluated according to ADEC regulations specifying that a technology have the continuous capability to detect a leak equal to not more than one percent of daily throughput. In terms of response time, the regulations specify only that a system be capable of detecting leaks "promptly." Response times from field performance data are presented in the evaluation, but it is the pipeline controller's responsibility to establish an appropriate response time for his/her pipeline.

4.1.2.2 Accuracy

Accuracy is a measure of LDS performance related to estimation parameters such as leak flow rate, total volume lost, and leak location (API, 1995b). A system that estimates these parameters within an acceptable degree of tolerance, as defined by the pipeline controller/company, is considered to be accurate. Often times an LDS will use existing pipeline instrumentation such as flow meters and pressure transducers in their processes. The accuracy of these systems is evaluated in terms of the accuracy, repeatability, and precision of the recommended or provided pipeline instruments themselves. Instrument accuracy represents the measurement performance of the instrument relative to that of an ideal device. Repeatability is a measure of the instrument's ability to consistently return the same reading for a given set of conditions.

Precision is a measure of the smallest change that can be seen in the output of the instrument.

For this project, leak location accuracy is discussed in terms of the capability of a technology to locate the leak within a certain percentage of a given pipe segment or within so many feet of an indicating sensor.

4.1.2.3 Reliability

Reliability is a measure of the ability of an LDS to render accurate decisions about the possible existence of a leak on a pipeline (API, 1995b). It is directly related to the probability of detecting a leak, given that a leak does in fact exist, and the probability of incorrectly declaring a leak, given that no leak has occurred. A system which incorrectly declares leaks is considered to be less reliable; however, if the system has the capability to use additional information to disqualify, limit, or inhibit an alarm, a high rate of leak declarations may be considered less significant.

Reliability pertains only to the leak detection hardware and software, not the SCADA system, pipeline instrumentation, communication equipment, or any other factor beyond the control of the vendor. Reliability can be managed through controller response and established procedures; however, unless the LDS automatically adjusts to decision thresholds, these procedures cannot be used to discriminate between systems. For this project, the reliability of a leak detection technology is evaluated in terms of the frequency and cause of reported false alarms on operating pipeline systems, and the ability of the LDS to automatically evaluate line conditions and adjust alarms thresholds.

4.1.2.4 Robustness

Robustness is a measure of an LDS's ability to continue to function and provide useful information, even under changing conditions of pipeline operation (API, 1995b). A system is considered robust if it continues to perform its principle functions under less than ideal conditions. For this project, robustness is evaluated in terms of the capability of the LDS to distinguish between normal transient operating conditions and real leak events, and the ability to automatically make temporary system adjustments or disable certain leak detection functions as needed. Robustness is also evaluated in terms of the ability of an LDS to continue to perform in the event that an instrument is lost or goes off line.

4.1.3 Transferability/Feasibility

This criterion requires a close examination of expected pipeline operating conditions. The performance issues presented in Section 3.4 outline some typical operating conditions that may preclude the installation or limit the effectiveness of certain LDS technologies. Regional considerations should also be used in determining whether a specific LDS technology will be transferable or feasible for use on a specific pipeline. A sound understanding of existing and expected pipeline conditions together with LDS system limitations is necessary for the successful implementation of any LDS technology. Advantages and operational situations that should be avoided are presented for each leak detection technology.

4.1.4 Compatibility/System Requirements

The operating requirements of each LDS, including instrumentation, communications, sampling frequency, and controller training are presented under this criterion to enable the potential user to further evaluate whether the LDS is compatible with a specific pipeline system.

4.1.5 Environmental Impacts

Environmental impacts are assessed under the BAT regulations by determining "whether the environmental impacts of each alternative technology, such as air, land, water, energy, and other requirements, may offset any anticipated environmental benefits." Internally installed LDSs typically do not represent a significant change to the surrounding environment. Externally installed systems may require excavation or other disturbances to the environment surrounding the pipeline system.

4.1.6 Regional Considerations

Regional considerations are key in selecting LDSs for Alaskan pipeline operations. Alaskan operations are characterized by long distances, large and rapid changes in elevation, large changes in throughput due to weather events in production or terminal areas, annual temperature variations of up to 160 °F, and limited ground access along some pipe segments. These regional considerations may be key in the selection of an LDS alternative, its communications system, or both.

Long distance pipelines require multiple pump stations to maintain line pressure. The selected LDS must be capable of highly accurate inventory, or be segmented between pump stations, to compensate for use of surge tanks and operational changes at individual stations.

Elevation changes create pressure differentials within the pipe and, under lower throughput, may cause slack-line conditions to exist in downhill segments. If appropriate, the selected LDS must be able to compensate for large pressure variations (for pressure differential-based systems) or for transient storage terms (for pipeline volume-balance based modeling systems).

Not all pipelines are ground-accessible throughout the year. Therefore, to limit costs, pipelines in such areas should rely on LDSs that do not require frequent maintenance or calibration events.

4.1.7 Field Performance

The evaluation of actual LDS field performance is essential to substantiate vendor claims of system sensitivity, accuracy, reliability, and robustness. Industry references provided by the vendors and ADEC were contacted to verify and comment on the performance of their LDS.

4.1.8 Cost

Vendors were extremely reluctant to provide absolute hardware and software costs for their leak detection systems because there is no way to accurately extrapolate the numbers to a pipeline without knowing its exact configuration. They also indicated that there is a great deal more to the cost of owning an LDS than the bare bones system price (i.e., the relative cost of instruments, maintenance or life cycle costs, and costs associated with adding more lines to the system). For these reasons and unless the vendors provided actual numbers, the costs associated with each technology are discussed only qualitatively. A general LDS pricing discussion is presented in the paragraph below. There are often tradeoffs between the price of an LDS and its performance. Highly effective systems (sensitive, accurate, reliable, and robust) ultimately will cost more to implement and maintain. It is up to the pipeline company to establish pipeline-specific performance standards and weigh the costs and benefits of an LDS.

In general and excluding costs for additional instrumentation and maintenance, installed and tuned software-based volume balance and pressure analysis systems are available for less than $200,000. Ultrasonic volume balance systems typically are more expensive because they require the purchase of vendor-specific clamp-on flow meters at about $35,000 to $40,000 each. Real time transient models run between $200,000 and $1,000,000, depending on pipeline configuration. External liquid-sensing and fiber optics cables are about $5 to $15 per foot installed. Accompanying hardware and software is required for each cable segment at prices between $10,000 and $50,000. Costs for soil gas/tracer sensing technologies are about $15 per probe (a probe needs to be installed about every 20 feet) with additional costs for installing field stations every two miles (approximately $50,000), and a central computer with specialized software ($10,000-$20,000). Acoustic emissions *AE* system can be installed on a single pipeline segment of 200 to 300 feet (i.e., 2 sensor systems with a 2-channel ALM) for $5,000 to $12,000. Each additional segment requires a channel at an added cost of approximately $3,000.

5 REFERENCES

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6 GLOSSARY

Accuracy (Evaluation Criterion): The measure of leak detection system performance related to estimation parameters such as leak flow rate, total volume lost, and leak location. A system that estimates these parameters within an acceptable degree of tolerance, as defined by the pipeline controller/company, is considered to be accurate.

Accuracy (Instrument): The measurement performance of the instrument relative to that of an ideal device.

Alarm: A visual or audible notification to the pipeline operator that an anomaly has been detected that is outside the preset limits.

Algorithm: A mathematical rule or procedure for solving a problem.

Applicability/Availability: A best available technology evaluation criterion. Applicability ensures that any technology selected for use on a crude oil pipeline system was designed for that intended use. Availability refers to the commercial availability of a leak detection system and its components.

Best Available Technology: As defined under 18 AAC 75.990(9), means the best proven technology that satisfies the applicable requirements of 18 AAC 75.425(e)(4) and criteria of 18 AAC 75.445(k).

Bulk Modulus: The bulk modulus of a liquid is the reciprocal of its compressibility.

Compatibility/System Requirements: A best available technology evaluation criterion. The operating requirements of each leak detection system, including instrumentation, communications, sampling frequency, and controller training.

Computational Pipeline Monitoring (CPM): Algorithmic monitoring tools that are used to enhance the abilities of a pipeline controller to recognize anomalies which may be indicative of a product release. Also known as internal leak detection.

Cost: A best available technology evaluation criterion. The hardware and software costs associated with a vendor-specific leak detection system.

Effectiveness: A best available technology evaluation criterion dealing with the performance related aspects of a leak detection system. Effectiveness is evaluated in terms of sensitivity, accuracy, reliability, and robustness.

Environmental Impacts: A best available technology evaluation criterion. As defined in the regulations (18 AAC 75.445(k)), "whether the environmental impacts of each alternative technology, such as air, land, water, energy, and other requirements, may offset any anticipated environmental benefits."

External Leak Detection System: Externally based methods detect leaking product outside the pipeline and include traditional procedures such as right-of-way inspection by line patrols, as well as technologies like hydrocarbon sensing via fiber optic or dielectric cables.

False Alarms: Transient alarms that are not caused by an actual product release.

Field Performance: A best available technology evaluation criterion. The evaluation of actual field performance to substantiate vendor claims of system sensitivity, accuracy, reliability, and robustness.

Filter: A device or algorithm to remove unwanted components from a process signal.

Flow Meter: Devices installed on pipelines to measure product flow through the line. Several different types of flow meters are used in the industry including orifice plates (differential pressure), turbine, positive displacement, mass flow (Coriolis type), and ultrasonic time-of-flight (clamp-on).

Internal Leak Detection System: Internally based methods use instruments to monitor internal pipeline parameters (i.e., pressure, flow, temperature, etc.), which are inputs for inferring a product release by manual or electronic computation. Also known as computational pipeline monitoring.

Line Pack: The actual volume of product in a pipeline segment. It is a function of pipe diameter, wall thickness and material, the thermal expansion coefficient of the pipe material, the reference density of the product, pressure, and temperature.

Master Terminal Unit (MTU): A component of the SCADA system, usually located in the control room, that gathers and displays process data from the field remote terminal Units (RTUs) and programmable logic controllers (PLCs).

Multiphase: The condition where a pipeline contains liquid product, gas-phase product, and water.

Noise: An unwanted component in a process signal or the part of a signal which does not represent the quantity being measured.

Pig: A device designed to move through a pipeline for purposes of cleaning, product separation, or information gathering.

Pipeline Controller: A person who is responsible for the monitoring and direct control of the pipeline.

Polling: A type of SCADA communications protocol in which sequential requests for process data from field units are issued by the master terminal unit (MTU).

Precision: A measure of the smallest change that can be seen in the output of the instrument.

Pressure Analysis: A leak detection method based on the analysis of pipeline pressure variations and the identification of the rarefaction wave produced when product breaches the pipeline wall. Most internal leak detection systems also use pressure analysis to locate leaks.

Pressure Transducer: Instruments installed on pipelines to measure the pressure of the product within the line. Conventional pressure transducers generally are of the electronic sensing type with various means of discerning pressure (piston, diaphragm, strain gauge, piezoelectric sensors, variable capacitance, and variable element). Pipeline pressure is measured by the displacement of these devices in response to fluid pressure and is converted electronically to an appropriate current, voltage, or digital output signal.

Product characteristics: The physical properties of a product as defined by its density, specific weight, pressure, surface tension, bulk modulus of elasticity, vapor pressure, and viscosity.

Programmable Logic Controller (PLC): A SCADA system component, typically installed at a field site, that gathers process data from instruments for transfer to the MTU.

Protocol: The specifications of the messages between remote terminal units (RTUs) or programmable logic controllers (PLCs) and the master terminal unit (MTU).

Rarefaction Wave: Also called an acoustic, negative pressure, or expansion wave. It is the undulation resulting when product breaches the pipeline wall and there is a sudden drop in pressure at the location of the leak followed by rapid line repressurization a few milliseconds later. The resulting low-pressure wave travels at the speed of sound through the liquid away from the leak in both directions.

Real Time Transient Modeling (RTTM): A leak detection method involving the computer simulation of pipeline conditions using advanced fluid mechanics and hydraulic modeling. RTTM software can predict the size and location of leaks by comparing the measured data for a segment of pipeline with the predicted modeled conditions.

Regional Considerations: A best available technology evaluation criterion assessed in terms of Alaskan pipeline operations (i.e., long pipeline distances, large and rapid changes in elevation, energetic submarine/underwater environments, annual temperature variations of up to 160 °F, and limited ground access along some pipe segments).

Reliability: A measure of the ability of a leak detection system to render accurate decisions about the possible existence of a leak on a pipeline.

Remote Terminal Unit (RTU): A SCADA system component, typically installed at a field site, that gathers process data from instruments for transfer to the MTU.

Repeatability: A measure of an instrument's ability to consistently return the same reading for a given set of conditions.

Robustness: A measure of a leak detection system's ability to continue to function and provide useful information, even under changing operating conditions.

SCADA: An acronym for Supervisory Control and Data Acquisition, the technology that makes it possible to remotely monitor and control pipeline facilities.

Segment (of a Pipeline): A pre-defined portion of pipe that has its own unique indivisible identity and is usually bounded by flow measurement and/or pressure transducer instrumentation.

Sensitivity: The composite measure of the size of leak that a system is capable of detecting, and the time required for the system to issue an alarm in the event that a leak of that size should occur

Slack Line: The condition where a pipeline segment is not entirely filled with product or is partly void.

Transferability/Feasibility: A best available technology evaluation criterion requiring a close examination of expected pipeline operating conditions. Pertains to the advantages and operational situations that should be avoided for each leak detection technology.

Transient: Any unsteady flow or pressure condition in a pipeline. Transients typically arise from operations such as valve changes and pump starts or shutdowns. They are also created when a leak occurs on a pipeline. For non-leak events, transients result in line pack changes that must be accounted for in leak detection.

Volume Balance: A leak detection method based on measuring the discrepancy between the incoming (receipt) and outgoing (delivery) product volumes of a particular pipeline segment.